

Constraining self-sourcing stratigraphic plays in North Sumatra: Integration of basin-petroleum system and stratigraphic forward modeling

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ABSTRACT

Stratigraphic traps are typically identified and delineated using 3D seismic analysis or by integrating well data. These plays involve greater exploration uncertainty than conventional traps, especially in regions where multiple petroleum systems coexist. A notable example is the self-sourcing stratigraphic trap, where hydrocarbons migrate laterally within coeval rock formations. This challenge is particularly significant in frontier areas lacking 3D seismic data and with limited well data. Therefore, developing a reliable methodology is essential to accurately identify potential stratigraphic trap zones while effectively accounting for the complex interactions within petroleum systems.

This study integrates stratigraphic forward modeling (SFM) and basin and petroleum system modeling (BPSM) to better constrain self-sourcing stratigraphic traps. The North Sumatra Basin was selected as the study area because it features a complex petroleum system involving three source rocks and various trapping mechanisms, including stratigraphic traps from the Middle Miocene. The systematic approach demonstrated in this study involves four key stages: (1) assessing geochemical evidence, (2) using SFM to delineate trap zones, (3) simulating organic matter distribution, and (4) applying BPSM to evaluate source rock maturation and hydrocarbon expulsion. This systematic approach provides a cost-effective framework for early-stage hydrocarbon exploration, helping geoscientists de-risk prospects before committing to high-cost data acquisition like 3D seismic surveys. It is particularly suited for evaluating stratigraphic traps associated with self-sourcing plays and has potential applications in unconventional resource exploration, including shale gas. Regionally, this research provides the first geochemical evidence of oil mixing in the area and presents conclusive insights into the four active petroleum system plays, potentially redefining exploration strategies in the region.

1. Introduction

Stratigraphic traps (Levorsen, 1966; as cited in Binns, 2006) gained broader attention following the call to ‘search for the subtle trap’ (Halbouty and Halbouty, 1982) and have since become important targets in hydrocarbon exploration worldwide (Pettingill, 1998; Fugelli and Olsen, 2005; Stoker et al., 2006; Biteau et al., 2014; Dolson et al., 2018; Stirling et al., 2018; Amy, 2019; Langhi et al., 2020; Counts et al., 2021). The primary method for identifying these traps is seismic imaging, particularly through the application of 3D seismic attribute analysis (Reymond and Stampfli, 1996; Bahmani et al., 2020; Naseer, 2024). Alternatively, it can also be investigated through the integration of seismic and well-log data (Torrado et al., 2020), or solely through detailed sedimentological core descriptions and well-log interpretation

within a high-resolution sequence stratigraphic framework to delineate pinch-out zones (Olsen and Steel, 1995).

The exploration risk associated with stratigraphic plays is generally higher than that of conventional structural traps (Straccia and Prather, 1999; Prather, 2003; Fugelli and Olsen, 2005; Loizou, 2014; Mathieu, 2018; Counts et al., 2021), and this risk is further amplified in regions where multiple petroleum systems coexist. One particular example is the stratigraphic trap that develops as a self-sourcing play, where hydrocarbons are generated and accumulated within the same or closely associated lithological units, resulting in short-distance migration (Ferguson, 1988). The term self-sourcing in this study refers to a petroleum system in which migration occurs within coeval rock formations via adjacent lateral migration (Sola et al., 2018; Jihai and Huang, 2019; Rudra et al., 2024).

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The challenges outlined above highlight the need for a methodology capable of effectively delineating potential stratigraphic trap zones while addressing petroleum system complexities, particularly in frontier areas lacking 3D seismic coverage with sparse well control. This study aims to explore how the integration of SFM with BPSM can aid in identifying stratigraphic traps and the presence of self-sourcing petroleum plays. The North Sumatra Basin (NSB) is chosen for this study because it hosts a complex petroleum system shaped by the interaction of three source rocks and various trapping mechanisms, including stratigraphic traps in the Middle Miocene (Adlan et al., 2025). The study has two primary objectives: first, to investigate the petroleum system play within coeval rock formations (e.g. Middle Miocene Baong Formation); and second, to better constrain self-sourcing stratigraphic trap by integrating two complementary modeling techniques, SFM and BPSM. Although these techniques have traditionally been developed separately, this study demonstrates their potential as mutually reinforcing tools to reduce geological uncertainty in exploration. This study not only provides conclusive evidence of self-oil mixing in the NSB, but also proposes a cost-effective strategy for evaluating underexplored zones, particularly in frontier settings where stratigraphic traps are associated with self-sourcing plays. Moreover, this approach has the potential to be applied in the exploration of unconventional resources, such as shale gas.

2. Background

2.1. Geological setting

The Cenozoic NSB formed as a back-arc basin divided into two regions by the Rayeu Hinge (Kingston, 1978; Davies, 1984) (Fig. 1). West of the Rayeu Hinge, the most significant hydrocarbon field, Arun, was discovered in 1971 and has produced 14 TCF of gas and 900 MM barrels of condensate from an Early Miocene reefal limestone (Barber et al., 2005; Lunt, 2019). In contrast, the area east of the Rayeu Hinge, which is the focus of this study, comprises compartmentalized north-south trending horsts and grabens characterized by higher heat flow (Siringoringo et al., 2024) and the presence of smaller hydrocarbon fields (Barber et al., 2005).

The Middle Miocene target interval, Baong Formation (Fig. 2), in NSB known to have stratigraphic traps (Perdana et al., 2020; Buntoro et al., 2022; Wardhana et al., 2024). This formation represents a post-rift marine transgressive phase deposited between 15.5 and 10.5 Ma (Langhian–Serravalian–lower Tortonian), with the lower interval comprising deep-marine facies and the upper interval characterized by

shallow-marine sandy facies (Fig. 2) (Kjellgren and Sugiharto, 1989; Adlan et al., 2025). The lower unit of this interval (Fig. 2), the Baong Shale, has been reported to contain an average Total Organic Carbon (TOC) content of 0.91 wt% (Caughey and Wahyudi, 1993), with values ranging from 0.54 wt% to 1.62 wt% (Anderson et al., 1993). The overlying sandstone interval, along with the sand lenses within the lower shale interval, are recognized as effective hydrocarbon reservoirs in the region (Atkinson et al., 2005; Wardhana et al., 2022).

2.2. Organic matter modelling concepts

Characterization of organic-rich sediments depends on understanding paleotopography, sediment supply and distribution, and infill dynamics (Granjeon and Joseph, 1999; Granjeon and Chauveau, 2014; Hawie et al., 2015). SFM offers a process-based numerical approach to simulate sedimentation using physical approximations (Granjeon and Joseph, 1999; Granjeon and Chauveau, 2014). This approach has recently been used to simulate the production, transport, preservation, and degradation of organic matter over geological time (Granjeon, 1996; Granjeon and Joseph, 1999; Granjeon and Wolf, 2007; Al-Wazzan et al., 2022). In terms of in situ organic matter productivity, the rate at which chlorophyll-containing organisms (e.g., phytoplankton and bacteria) assimilate carbon is controlled by CO₂, sunlight, nutrients, water depth, and temperature (Berger et al., 1989; Bouman et al., 2005; Kyewalyanga, 2016). Organic production rate in marine sediments can be quantified by the following equation:

$$PP_{0,k} = a_{1,k} Q_{\text{nutrient}}^{b_{1,k}} \quad (\text{Granjeon and Chauveau, 2014})$$

where “PP” is the primary production rate (gC.m⁻².yr⁻¹); “Q_{nutrient}” is the nutrient supply; “a_{1,k}” and “b_{1,k}” are constants related to sediment class.

Following organic matter productivity, the model also accounts for the sinking of organic particles from the photic zone to the seafloor via the ballast effect (Martin et al., 1987; Berger et al., 1989; Honjo et al., 2008). Residence time in the water column and organic degradation are described by Martin’s law (Martin et al., 1987), which models an exponential decrease with water depth:

$$F_{\text{org}} = 0.409 PP^{1.41} (z/100)^{-n} \quad (\text{Martin et al., 1987})$$

where “F_{org}” is the exported organic flux (gC.m⁻².yr⁻¹) reaching the sea bottom and “n” is a constant equal to 0.86 and z is depth. The seafloor transport of residual organic matter is simulated using the bedload equations for inorganic sediments (Granjeon and Chauveau, 2014). Organic matter degrades within the first centimeter below the water-sediment interface (Wenzhöfer and Glud, 2002), with preservation influenced by sedimentation rate and local oxygen/redox

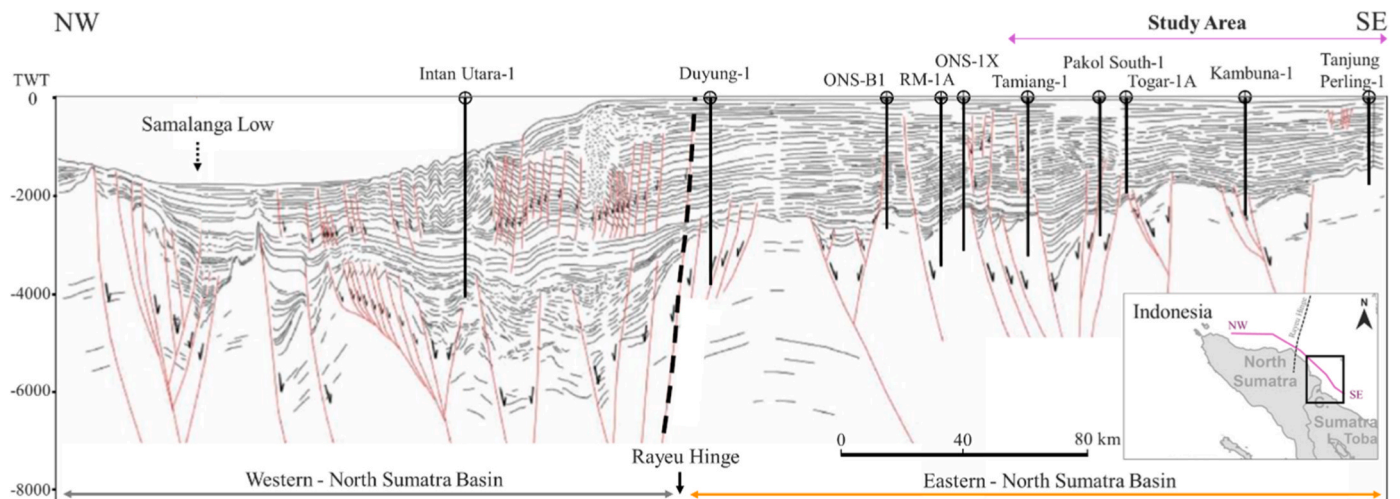


Fig. 1. Regional interpreted seismic section of the NSB from an unpublished report by the Ministry of Energy and Mineral Resources of Indonesia. The eastern region, the focus of this study, is separated by the Rayeu Hinge.

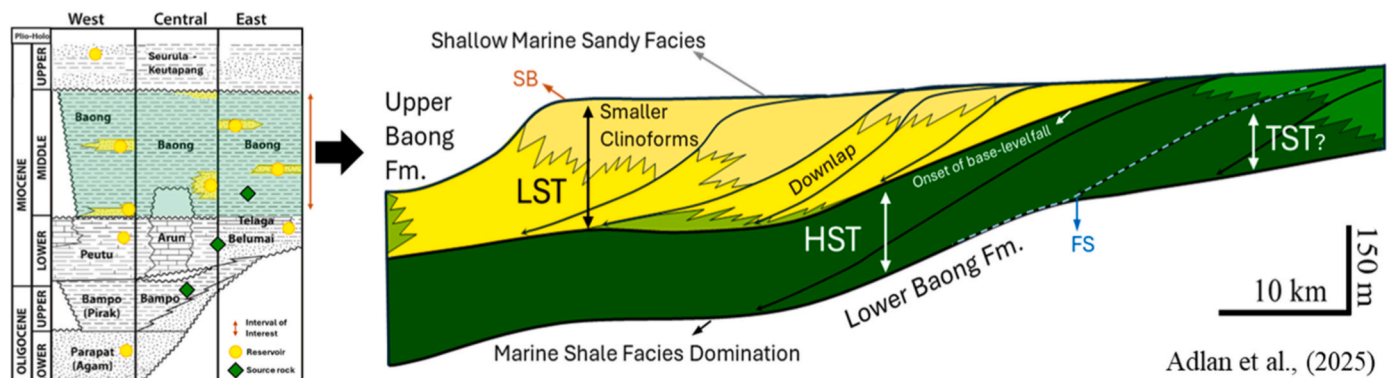


Fig. 2. Stratigraphic column of the Greater NSB (left, modified from Kingston, 1978). The Baong Formation, the interval of interest, spans 15.5 Ma to 10.5 Ma and is notable for its stratigraphic trap potential. Detailed stratigraphic information highlighting its upper sand and lower shale intervals is adapted from Adlan et al. (2025) (right).

conditions (Betts and Holland, 1991; Tyson, 1995, 1996). Overall, modeling parameters and their relationships are defined by empirical equations, as summarized and explained in the literature by Granjeon and Chauveau (2014) and Bruneau et al. (2017).

3. Data and methods

3.1. Dataset and modeling boundaries

Two oil seep samples, RA25 and RA124, collected during the 2024 field campaign from an area known for its anticline structures, were included in this study (Fig. 3). Biomarker and stable isotope data were compiled from unpublished geochemical reports of wells drilled between the 1980s and 2010s, including DST, RFT, and oil stain (migrant oil) samples from rocks with high extractable hydrocarbons. Along with seep samples, a total of 20 oil geochemistry datasets were used. The condition of the reports examined indicates that some biomarker (fragmentogram) reports are poorly preserved, while fragmentograms are missing for certain samples.

The modeling area, covering 13,000 km² primarily offshore (Fig. 3). Nine wells within the modeling boundary, excluding KST-22 and KST-24 wells, were incorporated into both organic matter-SFM and BPSM

(Fig. 3). All of the well data were obtained from the Center for Geological Survey, Ministry of Energy and Mineral Resources of Indonesia.

3.2. Oil geochemistry: sample and data suites

Two oil seeps were sampled near an active oil field (RA124 and RA25; Fig. 3) and prepared for gas chromatography (GC) and gas chromatography-mass spectrometry (GC-MS) analyses. Prior to the analyses, seep samples were diluted using 40 ml of n-pentane for deasphaltenation. The aliquot was left in the fridge (24h) and later centrifuged for 10 min at a rate of 2500–3000 rpm (rate per minute). After the asphaltene was separated, the aliquot was evaporated and hexane was added to each sample for column chromatography to separate saturated and aromatic hydrocarbons as well as non-hydrocarbon (polar) fractions. Solvents used for saturated, aromatic, and polar fractions were 25 ml of hexane, 25 ml of dichloromethane (DCM), and 25 ml of DCM and methanol, respectively. The saturated hydrocarbon, branched and cyclic alkanes were isolated using a packed silicalite chromatographic column as described by West et al. (1990), in which the latter were injected into GC and GC-MS instruments.

An Agilent 6890N GC instrument with DB-1 (J&W) fused-silica capillary column (20m × 0.21 mm i.d.) coupled with a flame ionization detector (FID) was employed for GC analysis. Meanwhile, GC-MS analysis was conducted using an Agilent 6890 GC coupled to an Agilent 5973 series mass selective detector (MSD). The GC is fitted with DB-5 (J&W) fused-silica capillary columns (60 m × 0.25 mm i.d.) and an Agilent 7673 auto-injector programmed with split/splitless mode and helium (He) as carrier gas. The injection temperature was set to 250 °C, while the column temperature was predefined initially at 35 °C and increased to 300 °C at a rate of 6 °C/min. Fragmentogram peaks were then identified on Agilent MSD ChemStation to get certain biomarker parameters. Note that the degree of biodegradation, if present, was assessed using classification from Peters et al. (2005).

3.3. Chemometric and principal component analyses

The oil geochemistry data used in this study cover all producing reservoirs in the area, from young to old, including the Keutapang, Baong, Bampo, and Malacca/Peutu reservoirs. The primary challenge in establishing a genetic relationship for each oil in this study was the large quantitative dataset with limited qualitative data. Principal component analysis (PCA) and chemometric methods proved effective in addressing this challenge (Peters et al., 1999, 2005, 2007; Wang et al., 2018; Hartono et al., 2023). The analysis was performed using PAST 4.03 software (Hammer and Harper, 2001). The genetic relationship was determined using the Euclidean algorithm, following Hartono et al.

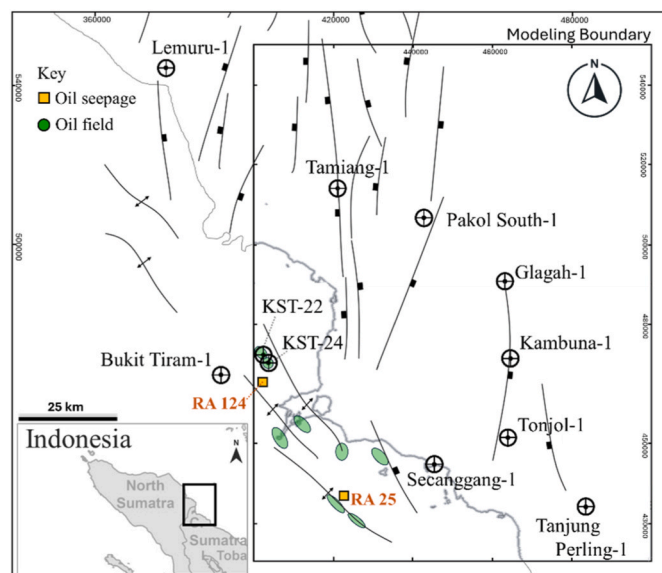


Fig. 3. Location and modeling boundaries in the eastern NSB. Structural information is obtained and modified from Bachtar et al. (2014).

(2023). This study utilizes twenty-four source-related biomarker parameters, including pristane/phytane, pristane/*n*C₁₇, phytane/*n*C₁₈, degree of waxiness (Peters et al., 2005), carbon preference index (CPI; Bray and Evans, 1961), terrigenous aquatic ratio (TAR; Bourbonniere and Meyers, 1996), C₁₅/C₁₆ bicyclic alkanes (drimane/homodrimane), rearranged bicyclic/bicyclic alkanes, drimane/C₃₀ hopane, C₁₉/C₂₃ tricyclic terpanes, C₁₉/C₂₀ tricyclic terpanes, C₂₀/C₂₁ tricyclic terpanes, C₂₁/C₂₂ tricyclic terpanes, C₂₃/C₂₄ tricyclic terpanes, C₂₄/C₂₅ tricyclic terpanes, C₂₆/C₂₅ tricyclic terpanes, C₂₄ tetracyclic terpane/C₂₃ tricyclic terpane, trisnorhopane/trisnorhopane (Tm/Ts) (Peters et al., 2005), C₂₉/C₃₀ hopanes, oleanane/C₃₀ hopane, C₂₇/C₂₉ steranes, C₂₈/C₂₉ steranes, diasteranes/steranes, and total hopanes/total steranes. All parameters were normalized using minimum-maximum normalization (Wang et al., 2018) before analysis. In this study, parameters influenced by maturation, such as CPI, rearranged bicyclic/bicyclic alkanes, and Tm/Ts, were used, as they provide insight into carbonate material precursors, which are essential for oil classification (Palacas et al., 1984; Price et al., 1987; Hartono et al., 2023). Note that one condensate sample from Kambuna-2 (API 52°) was excluded from the analysis due to its low biomarker composition, likely resulting from high thermal maturity (Peters et al., 2007).

3.4. Fluid inclusion stratigraphy (FIS)

Barker and Smith (1986) first demonstrated the use of mass spectrometry to obtain detailed molecular information from petroleum inclusions. The refined technique, Fluid Inclusion Stratigraphy™ (Fluid Inclusion Technologies, Inc.), is used here to analyze organic and inorganic volatiles in fluid inclusions from cuttings. In this study, drill cuttings from the Baong Formation interval of the Pakol South-1 and Tanjung Perling-1 wells were used. The samples were first washed and subjected to magnetic separation to remove potential contaminants from mud additives (e.g., gilsonite). The samples were then loaded into an autosampler and heated in a vacuum for a minimum of 24 h to remove adsorbed organic and inorganic volatile materials, which are known to interfere with mass spectrometer analysis (Adlan et al., 2020). The samples were then crushed to release the analytes from the inclusions before being introduced into an automated high-vacuum system (Hall, 1997), which is connected to a Quadrupole mass spectrometer. The mass spectrometer is used to analyze low molecular weight hydrocarbons, CO₂, H₂S, and other organic compounds with a mass/charge ratio of $1 \leq m/z \leq 180$. Both inorganic and organic species with 13 or fewer carbon atoms are detected, including aromatics, naphthenes, and paraffins. This analysis is comparable to the low molecular weight fraction of a whole-oil gas chromatographic-mass spectrometric (GC-MS) analysis (without devolatilization of the gas fraction). A limitation of the technique is that, since the quadrupole is front-ended with a GC, boiling point separation is not achieved, and all species are analyzed simultaneously. As a result, significant interference can occur among species with the same mass-to-charge ratio (Osukuku et al., 2023). The results are presented as mass-to-charge ratio (*m/z*), with the amplitude of the ion reflecting the abundance of species or gas mixtures. The primary log used in this study is shown in Table 1, which will be used to examine evidence of present petroleum or petroleum

Table 1
Main organic and inorganic species examined.

Mass (<i>m/z</i>)	Organic and inorganic species represented
15	C ₁ fragment (CH ₃ ⁺); largely methane
60	Acetic acid (CH ₃ COOH ⁺) is predominantly present, although in some cases, carbonyl sulfide (COS ⁺)
76	CS ₂ ⁺ plus hydrocarbons
78	Benzene (C ₆ H ₆ ⁺), with a possible contribution from carbon disulfide (CS ₂ ⁺)
97	Representation of the C ₇ alkylated naphthene fragment

migration within a specific stratigraphic interval, as demonstrated in previous studies (Liu et al., 2004; Girard et al., 2014; Volk and George, 2019; Osukuku et al., 2023).

3.5. Organic matter modeling framework

The simulated area for organic matter modeling covers 100 km × 130 km (Fig. 3) with 2 × 2 km grid cells (Table 2) and is constructed using the DionisosFlow™ SFM software. Simulation starts at the base of Lower Baong Shale (15.5 Ma) and ends at the top of Upper Baong Sand (10.5 Ma) covering a time interval of 5 Ma with a 0.1 Ma time step (Table 2). The parameters used for forward stratigraphic modeling were adapted from a previously validated simulation (Model A1) in the area (Adlan et al., 2025). The model incorporates three sediment classes (Adlan et al., 2025): coarse sand (1 mm), sand (0.25 mm), and shale (0.004 mm). A low-gradient slope of 2 m/km within an upper bathyal bathymetric setting was applied to represent the paleotopography during the initial depositional stage. A short-term eustatic sea-level curve from Haq (2014) was used, along with a subsidence rate of ~70 m per million years (Adlan et al., 2025). The sediment supply rate decreases from 575 km³/Ma to 450 km³/Ma over the modeled interval (Adlan et al., 2025). The sediment supply originates from the northeast (Adlan et al., 2025). To model this diagonal sediment source, two input sources are used: a northern source (8 km in length) and an eastern source (9.6 km in length), together representing the northeast supply. Details of the stratigraphic control parameters including paleotopography, eustatic trends, sediment supply variability and their potential interactions are provided in Adlan et al. (2025).

In addition to the classical parameters described above, the organic matter modeling approach used in this study is adapted from Al-Wazzan et al. (2022), applying an open marine scenario in which the diffusion coefficient of organic matter is set equal to that of fine sediment (Table 2). However, given the distinct stratigraphic controls of the Baong Formation compared to the shallow intrashelf basin conditions described by Al-Wazzan et al. (2022), a modified approach is required. This study employs a combination of two organic matter production models: (1) primary productivity as a function of distance to shoreline and (2) columnar primary productivity as a function of upwelling depth. These models are integrated to better represent the depositional and oceanographic conditions specific to the Baong Formation. The proximity of emerged land leads to high primary productivity, ranging from 300 to 400 gC·m⁻²·yr⁻¹ over extensive areas (Bruneau et al., 2017). In our study, which initiates from the upper bathyal zone at a distance from the shoreline, a reduced primary productivity value of 250 gC·m⁻²·yr⁻¹ is applied. On the other hand, for the columnar primary productivity vs. upwelling depth parameter, a value of 400 gC·m⁻²·yr⁻¹ PP is used. This value aligns with the range observed in the Lower Najmah Shale, where primary productivity varies between 215 and 525 gC·m⁻²·yr⁻¹ (Al-Wazzan et al., 2022). Global primary production is strongly influenced by thermocline topography (Pennington et al., 2006), as

Table 2
Input parameters for Organic Matter modeling.

Model size	100 × 130 km (2 × 2 km cell)
Time step	0.1 Myr
Time span	5 Ma
Grain-size classes	coarse sand (1 mm), sand (0.25 mm) and shale (0.004 mm)
Diffusion Coefficients*	0.003–0.009 km ² /kyr (Adlan et al., 2025)
Sed. Supply*	575 to 450 km ³ /Ma (Adlan et al., 2025)
Subsidence rates	~70 m/My (Lunt, 2019)
Eustatic Curve	Short-term Cenozoic (Haq, 2014)
PP-shore line	250 gC·m ⁻² ·yr ⁻¹
PP-upwelling	400 gC·m ⁻² ·yr ⁻¹ (z = 400m)
Degradation exp.	0.858 (Martin et al., 1987)

* A detailed description of the SFM setup and stratigraphic controls for this interval are referred to Adlan et al. (2025).

phytoplankton growth depends on upwelled water characteristics (Strickland et al., 1969; Barber et al., 1971). Near Indonesia, warm water buildup deepens the thermocline to ~200 m (Barber and Chavez, 1983; Pennington et al., 2006). To account for this, the depth of maximum primary productivity in this model is set at 400 m, following the productivity curve of Bruneau et al. (2017). Summary of the organic matter modeling input shown in Table 2. Note that temperature and salinity are not considered in organic matter modeling. The degradation exponent is set to 0.858, based on the mean value from Martin et al. (1987). Model validation involves comparing the simulated TOC patterns with observed well data (Table 3).

The organic matter modeling results illustrate the evolution of the initial TOC (%) distribution during deposition, which changes at each time step. This study uses a 0.1 Ma time step, meaning the total number of maps reaches up to 50, which presents a challenge for using these results as input for basin-petroleum modeling. To make these results suitable for basin modeling, we used TOC maps representing three key stages of deposition in the Lower Baong Interval (Fig. 4): the TOC map at the beginning (15.5 Ma), the midway TOC map (14 Ma), and the TOC map at the end of deposition (12.5 Ma). On the other hand, adaptation is required for basin modeling input, particularly in terms of layer conditioning of the Lower Baong shale. This study uses two depth structure maps (top and bottom) to create the Lower Baong shale layer. The layer in BPSM is then split into three proportional thickness partitions to accommodate the three TOC maps derived from forward modeling. The timing of the Lower Baong Interval spans 3 million years, from 15.5 Ma to 12.5 Ma, necessitating the uniform partitioning of this duration into three segments, each lasting 1 Myr. An illustration of this adaptation is summarized in Fig. 4.

3.6. Basin and petroleum system modeling

The basin and petroleum system modeling of Cenozoic stratigraphic sequences in the eastern NSB was constructed using Petromod™ basin modeling software. Seismic interpretation, including well-to-seismic correlation, was conducted in-house by the Center for Geological Survey, Ministry of Energy and Mineral Resources of Indonesia to generate horizon, stratigraphic, depth structure map and thickness maps for the BPSM framework used in this study (Fig. 5). The assigned ages of the stratigraphic layers were derived from Kingston (1978) and Lunt (2019). Note that the age of the interval of interest, the Baong Formation, has been confirmed through a biostratigraphic age review (Adlan et al., 2025). The basin history of the eastern NSB is reconstructed with input layers directly corresponding to formation, sedimentation, rifting, and erosion events throughout the basin's evolution (Table 4). Facies assignments for each layer were based on uniform lithology-derived properties obtained from existing literature (Lunt, 2019), except the Baong Formation which was assigned a grain size-based lithology

Table 3

Geochemical data availability for modeling validation (Fig. 3). TOC = Total Organic Carbon; HI = Hydrogen Index; Ro = Vitrinite Reflectance; Temp. = Temperature.

Well Name	TOC	HI	Ro	Temp.	Oil samples
Tamiang-1	v	–	v	v	–
Pakol South-1 ^(a)	v	v	v	v	–
Glagah-1	v	v	v	–	FIS ^(b)
Kambuna-1	–	–	–	v	–
Tonjol-1	v	v	v	–	–
Tanjung Perling-1 ^(a)	v	v	v	v	FIS ^(b)
Secanggang-1	v	v	–	v	–
KST-22	–	–	–	–	v
KST-24	–	–	–	–	v

^(a) Well with the most comprehensive and well-distributed data points in the Middle Miocene interval: Pakol South-1 and Tanjung Perling-1.

^(b) Hydrocarbon inclusion analysis (Fluid Inclusion Stratigraphy).

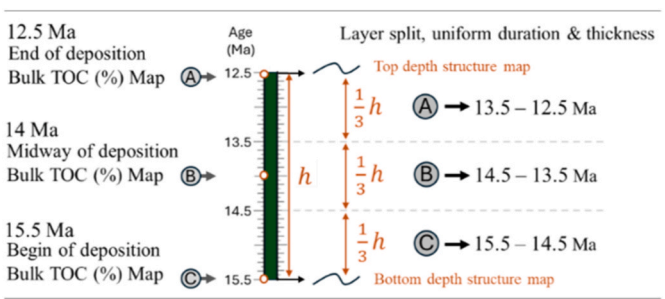


Fig. 4. Adaptation framework integrating stratigraphic forward modeling results as input for basin-petroleum system modeling of the Lower Baong Formation (from left to right). Layers A, B, and C represent stratigraphic subdivisions transferred from SFM to BPSM.

resulting from forward stratigraphic modeling results from (Adlan et al., 2025). Regional erosion in the area has been documented by Koesoemadinata et al. (1995, 1999). This study adopts erosion values from the nearby Pineueng-2 well, based on data reported by Lunt (2019).

This study focuses on the hydrocarbon generation and maturation of the Baong Formation, which requires TOC content, hydrogen index (HI), and source rock kinetics to define the formation's potential for organic matter maturation and hydrocarbon generation (Hantschel and Kauerauf, 2009). The TOC and HI values from the simulation (Fig. 5) were then corrected to reflect depositional conditions (Jarvie et al., 2007; Jarvie, 2012). Kerogen types were determined from well data within the study area and further compared to regional studies (Anderson et al., 1993; Caughey and Wahyudi, 1993). Boundary conditions were established based on key geological parameters. Paleowater depth (PWD) was assigned according to the depositional environment of each formation, following Lunt (2019), except for the Baong Formation, which was refined using recent findings by (Adlan et al., 2025). The sediment-water interface temperature (SWIT) was estimated using latitude-based calculations developed by Wygrala (1989). Heat flow (HF) values were adopted from Allen and Allen (2013) and Jarvis and McKenzie (1980), with 80–100 mW/m² assigned for the active synrift phase and 50–60 mW/m² for the post-rift phase. These HF values were further refined using present-day HF data of Sumatra (Siringoringo et al., 2024) and calibrated against vitrinite reflectance data to ensure consistency and constrain the possible range (Perkins et al., 2023).

For the 3D model, consistency was evaluated by extracting 1D data from multiple locations and comparing them with the well-based 1D model and its validation (Table 3), following standard practices in BPSM (e.g., Perkins et al., 2023; Turney et al., 2024). Using the calibrated model, source rock maturation was assessed through measured “Easy% Ro” values (Sweeney and Burnham, 1990). Additionally, the transformation ratio (TR), which quantifies the proportion of organic matter converted to hydrocarbons (Tissot et al., 1978; Peters and Cassa, 1994), was analyzed to determine the timing of hydrocarbon generation and maturation. Note that the primary results required for this stratigraphic trap study are the maturation map and TR, while the fault system and migration pathways between formations were not considered.

This basin modeling involves several key uncertainties. The model does not account for lithological variability within the formation, except for the middle Miocene interval (Adlan et al., 2025). Seismic data were unavailable, as only depth-converted maps for each interval were provided by the Geological Survey of Indonesia. As a result, the accuracy of the seismic interpretation and depth conversion could not be verified. Additionally, the thermal conductivities of facies were based on default values (Hantschel and Kauerauf, 2009).

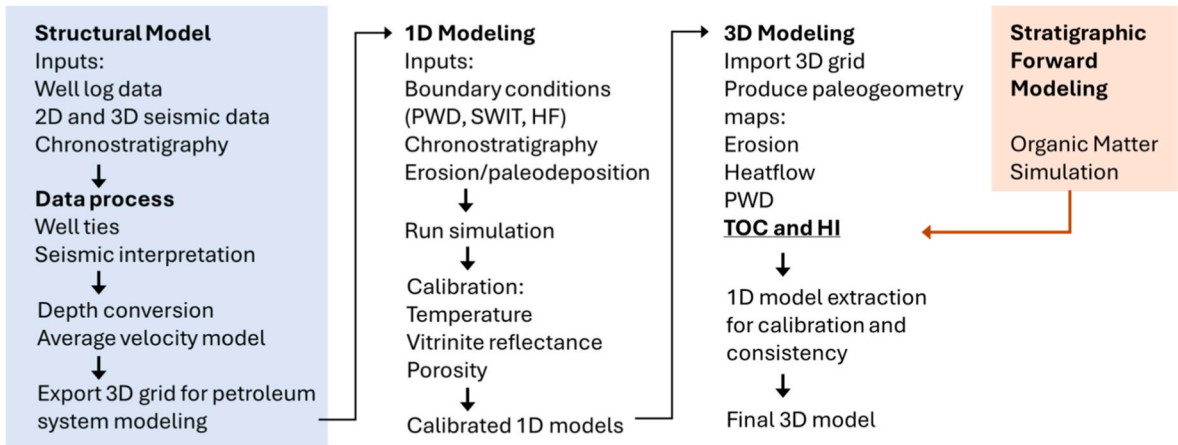


Fig. 5. Flowchart outlining the petroleum system model construction process, adapted from [Turney et al. \(2024\)](#). The initial stage (blue-shaded section) was carried out internally by the Center for Geological Survey, the Ministry of Energy and Mineral Resources of Indonesia. TOC and HI distributions were derived from stratigraphic forward modeling performed in this study.

Table 4
The basin and petroleum system modeling input.

Event name (Deposition/ Erosion/Hiatus)	Formation	Bottom age (Ma)	Top age (Ma)	Lithology assigned to layer ⁽¹⁾ and notes on associated regional events
Holocene Erosion	–	2.5	0	Erosion 250m onshore ⁽²⁾
Zanclean	Seurula-JR	6	2.5	Mix of 75 % shale and 25 % sandstone
Messinian	Keutapang	9	6	Mix of 70 % sandstone and 30 % shale
Barisan Event/ Hiatus ⁽³⁾	–	10.5	9	–
Serravalian- Tortonian	U.Baong	12.5	10.5	SFM result ⁽⁴⁾
Langhian- Serravalian	L.Baong	15.5	12.5	SFM result ⁽⁴⁾
Early Miocene Hiatus ⁽⁵⁾	–	17	15.5	–
Burdigalian- Langhian	Peutu	20.4	17	Limestone
Aquitanian	Belumai	23	20.4	Mix of 50 % sandstone and 55 % shale
Rupelian-Chattian	Bampo	33.9	23	Shale
Ypresian- Priabonian	Tampur	34	33.9	Dolomite (Basement)

¹⁾ Lithology assignments are based on [Kingston \(1978\)](#) and [Lunt \(2019\)](#).
²⁾ Present-day erosion is identified based on the S. Pineueng-2 well data ([Lunt, 2019](#)).
³⁾ No erosion in the study area ([Lunt, 2019](#)); however, a possible hiatus was suggested by [Koesoemadinata et al. \(1995, 1999\)](#).
⁴⁾ The distribution of the Upper Baong Sandstone and the Lower Baong Shale is based on [Adlan et al. \(2025\)](#).
⁵⁾ A hiatus or period of carbonate exposure has been suggested by ([Collins et al., 1996](#); [Jordan and Abdullah, 1992](#)).

4. Results

4.1. Oil geochemistry

The whole oil chromatography measurement shows that the *n*-alkanes distribution on both oil seepages RA25 and RA 124 display a unimodal peak with maxima on *n*C₁₁ and *n*C₁₂ (Fig. 6). The unresolved complex mixtures pattern or ‘hump,’ a signature of biodegradation, was not found in either seepage, indicating that the seepage samples are suitable for comparison with other oil data. The Pristane (Pr) is higher

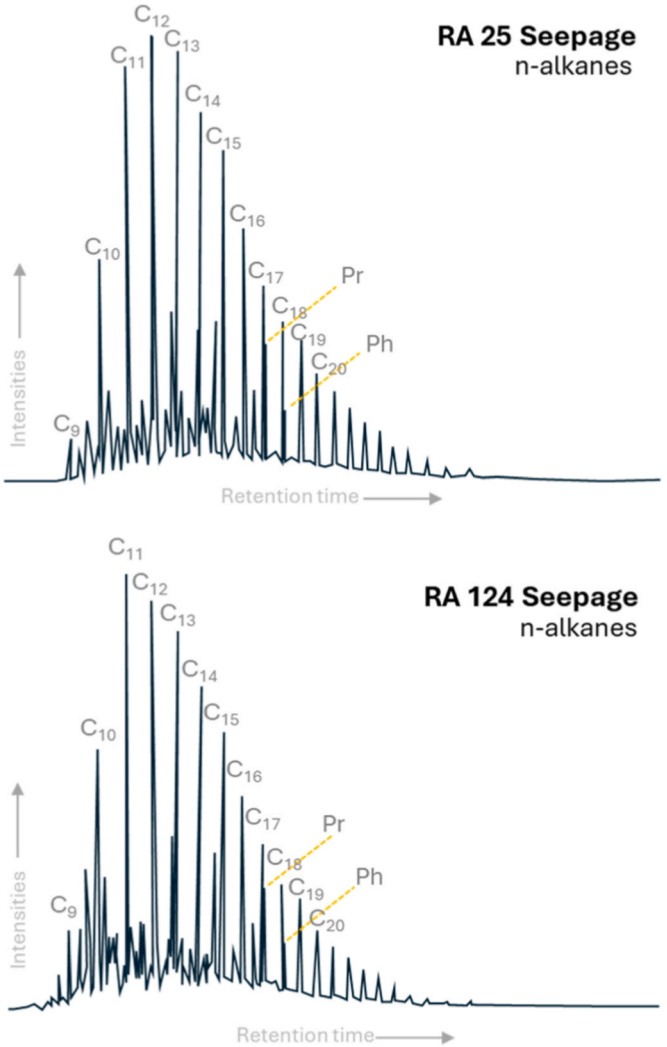


Fig. 6. The *n*-alkane distributions in both seepages show a unimodal peak with maxima below *n*C₁₃. The unresolved complex mixture (UCM) ‘hump,’ a biodegradation signature, was absent in both seepages.

than phytane (Ph) in both seepages, as reflected by the Pr/Ph ratio, which ranges from 2.19 in RA25 to 2.03 in RA124 (Fig. 6).

Here, the seepage m/z 191 results are compared to unpublished oil geochemistry data from the late Miocene Keutapang Formation reservoir (Keutapang Group, Bukit Tiram-1) and oil collected from the middle Miocene Baong Formation reservoir (Baong Group, Tanjung Perling-1) (Fig. 7). From the m/z 191 fragmentograms, the $C_{29}H/C_{30}H$ ratio is 0.5 for RA25 and 0.59 for RA124, while oils from the Keutapang and Baong groups show no significant difference compared to the seepages. The trisnorhopane (Tm) to trisnorneohopane (Ts) ratio on both seepages is 0.96 in RA25 and 1.27 in RA124 (Fig. 7), while oils from the Keutapang and Baong groups also contain higher Tm than Ts.

The key difference between the two seepages lies in the $C_{30}H/olefane$ ratio, with values of 0.61 in RA25 and 1.35 in RA124 (Fig. 7). The C_{29} 30-norhopane (series) is present in both seepage samples and in oil samples from the Baong Group (Fig. 7), but absent in oils collected from the younger Keutapang Group (Fig. 7). The distribution of steranes in both seepages shows no significant difference, with a slight dominance of C_{27} sterane ($\alpha\beta\beta$ 20R) in the m/z 217 fragmentograms. The relative abundances of C_{27} - C_{28} - C_{29} steranes ($\alpha\beta\beta$ 20R) in the RA25 seepage are 37 %, 29 %, and 33 %, respectively, while the RA124 seepage shows abundances of 40 %, 31 %, and 29 %, respectively. In comparison, oils from the Baong reservoir (Baong Group) have relative abundances of 18.5 %, 29.3 %, and 52.2 %, whereas oils from the younger Keutapang reservoir (Keutapang Group) contain 45.3 %, 20.7 %, and 34 %.

4.2. Mass spectrometric analysis of fluid inclusions

The examination of volatile ionic species trapped as fluid inclusions in the Baong Formation, based on FIS mass spectrometric analysis, is limited to 350 m in Pakol South-1, mainly in the lower part of the middle Miocene Baong Formation interval, while the FIS results from Tanjung Perling-1 cover the entire Baong Formation interval (Fig. 8A and B). The spectral display (black spike, Fig. 8) differs between Pakol South-1 and Tanjung Perling-1, corresponding to variations in total inclusion abundance (inclusion count). The m/z 15 track, which indicates CH_3^+ primarily derived from methane, shows a consistent abundance throughout the interval in Pakol South-1 (Fig. 8A). In contrast, in Tanjung Perling-1, methane inclusion occurs sporadically, while the remainder of the interval shows no methane inclusions and lacks other hydrocarbon inclusions as well (Fig. 8B). The m/z 97 naphthalenes ($C_7H_7^+$) are absent in the upper part of Pakol South-1 but show a significant relative occurrence in the lower part (Fig. 8A). In Tanjung Perling-1, naphthalene occurrence reaches a distinctive peak in the middle part of the Baong Formation, while it occurs sporadically throughout the rest of the interval. The remaining m/z 60 (acetic acid), m/z 78 (benzene), and m/z 76 (CS_2 and C_6^+ hydrocarbons) tracks exhibit an abundance trend that follows methane occurrence particularly in Pakol South-1.

The results show that hydrocarbon inclusions in the Baong Formation in Pakol South-1 consist of dry gas above 2170 m (upper Baong Formation), primarily C_1 with lesser amounts of C_2 - C_4 and no higher hydrocarbons (Fig. 8A). In contrast, the lower Baong Formation in Pakol South-1 between 2290 and 2350 m contains high methane and liquid hydrocarbon concentrations, with the presence of C_1 - C_{10} and minimal

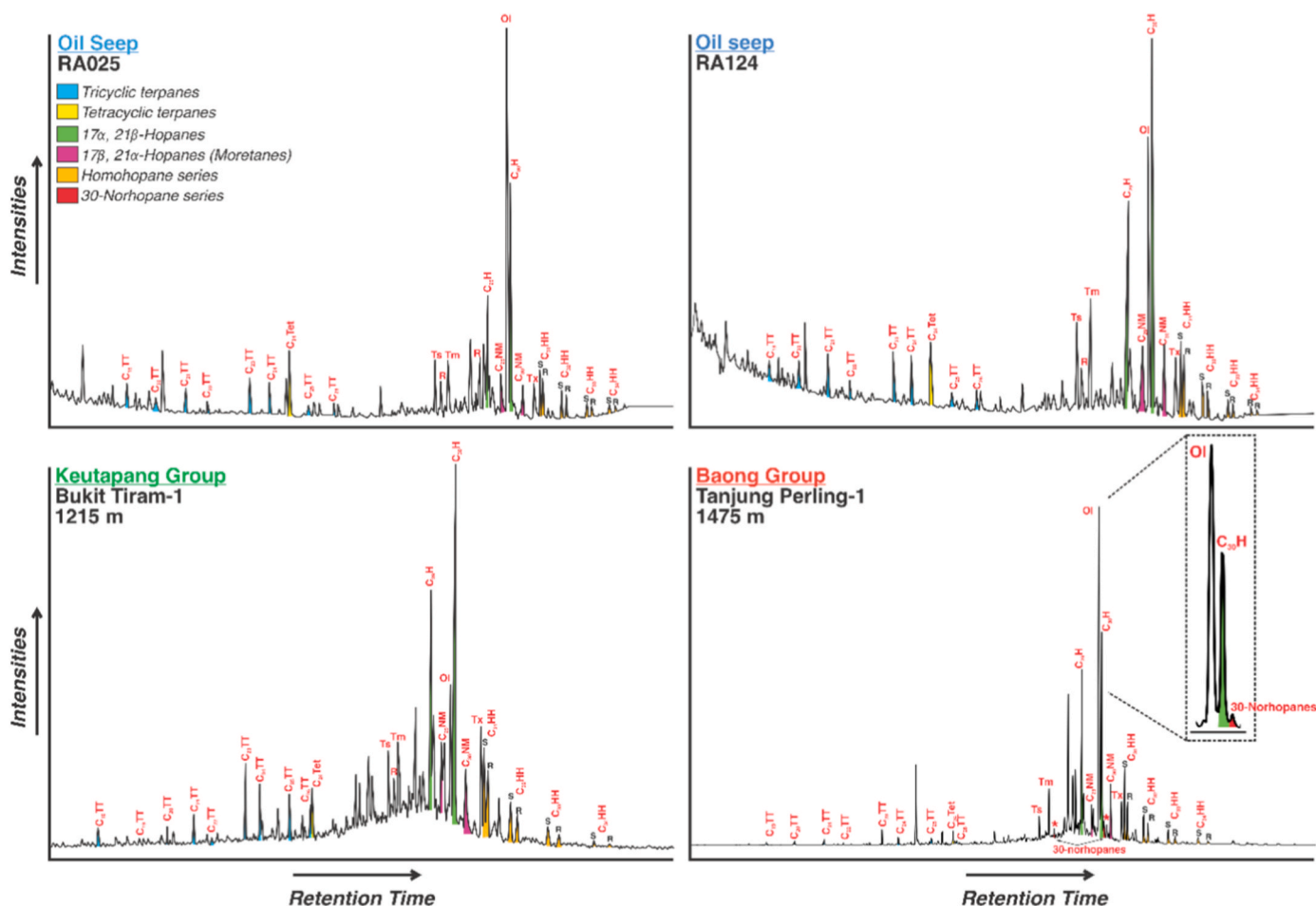


Fig. 7. Partial m/z 191 fragmentograms of oil seeps compared to oils from the Keutapang and Baong reservoirs, based on unpublished industrial reports. Oils in the Keutapang and Baong reservoirs differ, with the 30-norhopane series distinct in the Baong reservoir. The oil seeps closely resemble those in the Keutapang reservoir.

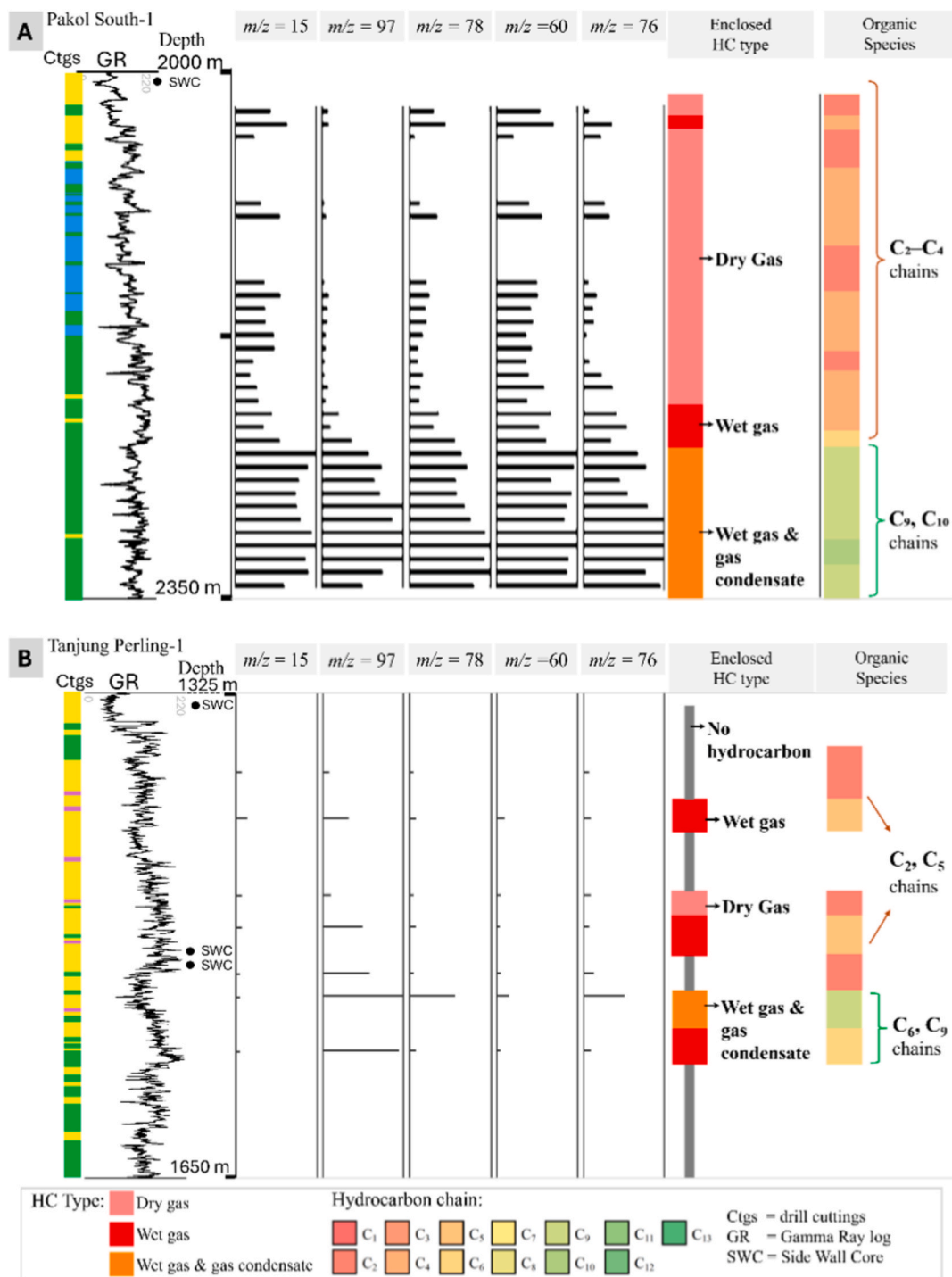


Fig. 8. The presence and relative bulk abundance of ionized hydrocarbon volatiles trapped as fluid inclusions in the middle Miocene Baong Formation: (A) Showing wet gas and condensate hydrocarbon types, predominantly in the lower interval, with the upper interval consisting of dry gas. (B) Tanjung Perling-1 well, where no hydrocarbon inclusions are observed except in the middle zone, which is dominated by wet gas, with some occurrences of dry gas and gas condensate.

abundance of C₆⁺ species (Fig. 8A). The results from Tanjung Perling-1 indicate either a lower abundance of inclusions or the absence of hydrocarbon-bearing inclusions in the Baong Formation interval (Fig. 8B). Most of the inclusions are present in the middle part of the interval between 1520 and 1575 m, consisting of a combination of wet gas and gas condensates, with C₁-C₁₀ hydrocarbons dominated by C₆ and C₉ chains. Minor occurrences of dry gas are also observed, primarily composed of C₂ and C₅ hydrocarbon species (Fig. 8B).

4.3. Forward modeling results for TOC

The simulated model reproduces the geometries and stratigraphic architectures of the entire middle Miocene Baong Formation, as highlighted in previous studies (Adlan et al., 2025). The lower interval (lower Baong Shale) began on a low-angle slope within the Highstand System Tract (HST) sequence framework (Fig. 2, Adlan et al., 2025), where paleotopography controlled accommodation for sediment deposition, at least until the slope toe was filled (Adlan et al., 2025). The simulated TOC exhibits a wide range of values from 0 to 12.7 wt%, with

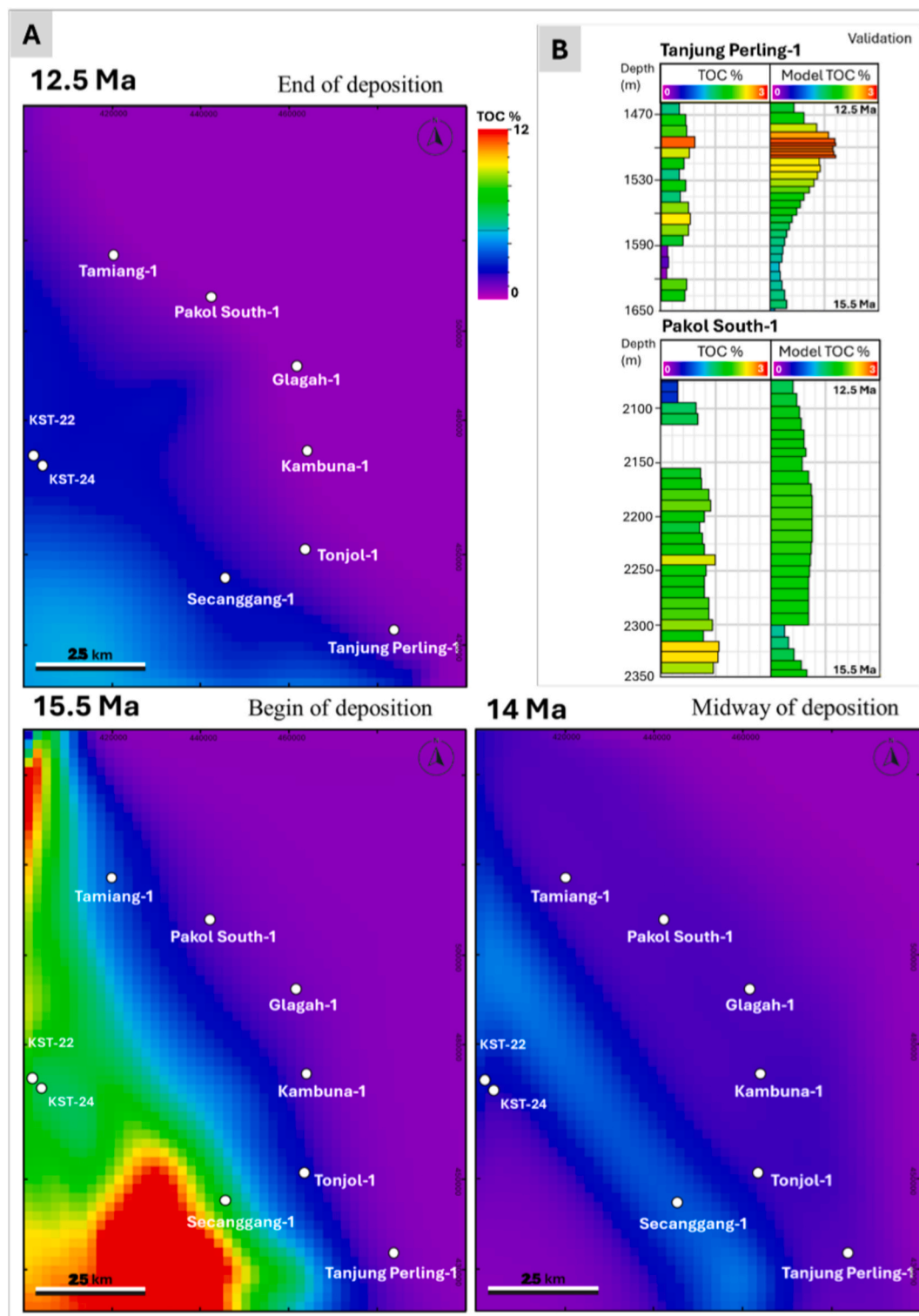


Fig. 9. A. Simulated TOC distribution of the Lower Baong source rock at the beginning of deposition (15.5 Ma), midway through deposition (14 Ma), and at the end of deposition (12.5 Ma); B. Examples of depth plots for TOC validation over time, through well Tanjung Perling-1 and Pakol South-1. Note: Remaining validation details can be found in **Supplementary Materials**.

higher TOC values predominantly found in the distal part of the basin to the southwest during the deposition of the lower Baong Formation (Fig. 9A). The northeast area exhibits the lowest values, ranging from 0 to 2.5 wt% (Fig. 9A). The TOC modeling results show that organic matter development is highest at the initiation of the lower Baong interval, with its distribution following the strike of the slope direction

throughout the time period from 15.5 Ma to the end of lower Baong shale deposition at 12.5 Ma (Fig. 9A). The simulated spatial distribution from this model aligns well with available data, with variations in organic content over time being consistent with observed values. The TOC% refers to the TOC obtained through laboratory measurements of well samples, while the Model TOC% represents the initial TOC derived

from the simulation. As this simulation measures the initial TOC, it is expected to have higher values than the present-day content. A similar trend is observed in the HI, which ranges approximately from 180 to 219 mg/gC in the southeast, reaching 100–130 mg/gC in the northeast. Note that the available data points for the HI from laboratory measurements are limited and fewer than those for the TOC data. Validation of TOC from the remaining well is provided in **Supplementary Materials** (Page 1–2).

4.4. Source rock maturation modeling

The 3D modeling results indicate that the entire Baong Shale source rock layer has reached early to peak maturity in the southwest of the modeling boundary, while the northeastern region remains immature (Fig. 10). In detail, the oldest Baong Shale layer (15.5 Ma) exhibits a maturity range of 0.6–1.09 %EasyRo. The middle (14.5 Ma) and youngest (12.5 Ma) Baong Shale layers show maturity ranges of 0.6–0.91 % and 0.6–0.8 % EasyRo, respectively (Fig. 10). Overall, the maximum present-day Transformation Ratio reaches 40 % in the southwest, particularly south of wells KST-22 and KST-24 (Fig. 10). The transformation ratio map closely reflects oil generation patterns, which are primarily concentrated in the southwest area of the modeling boundary. The results confirm that the lower Baong Shale source rock has the capacity to generate and expel hydrocarbons. Additionally, the findings suggest that oil expulsion from the Baong Shale source rock commenced around 2.5 Ma, reaching a maximum expelled mass of approximately 141 megatons of oil equivalent within the modeled area, equivalent to roughly 1.07 billion barrels of oil.

5. Discussion

5.1. Oil origins and evidence for a self-sourced play

Oil biomarker studies in the Greater NSB indicate the coexistence of at least three distinct source organofacies: marine shale, carbonaceous marine shale, and calcareous marine shale facies (Subroto et al., 1992; Sosrowidjojo et al., 1994). Among these, the carbonaceous marine shale facies are correlated with the Oligocene Bampo Formation, while the calcareous marine shale source rock is associated with the early Miocene Peutu Formation (Subroto et al., 1992). As the quantity and quality of organic matter (OM) depend on paleogeographic conditions (Hart and Hofmann, 2022), the relatively similar depositional settings of the three aforementioned source rocks present challenges for conventional hydrocarbon correlation in the Greater NSB (Lunt, 2019).

Analysis of our dataset indicates three possible oil sources based on tritacta sterane ratios and carbon isotopes, with these three clusters compartmentalized within reservoirs (Fig. 11A). Oils found in the Keutapang Formation reservoir (green highlight) tend to have higher C₂₇ sterane concentrations, indicating a dominant contribution from plankton, whereas those in the Baong reservoir (red highlight) are characterized by high C₂₉ sterane concentrations, possibly associated with land-plant input (Huang and Meinschein, 1979). The oil seeps and oils within the Baong reservoir unit contain considerable amounts of C₂₇ and C₂₉ steranes (Fig. 11A) which suggests a mixed organic matter input, typically associated with a fluvio-deltaic origin (Huang and Meinschein, 1979). However, carbon isotope analysis of the Baong Group oil reveals a clear separation (Fig. 11B), suggesting it likely originates from algal organic precursors. Although no isotope data are

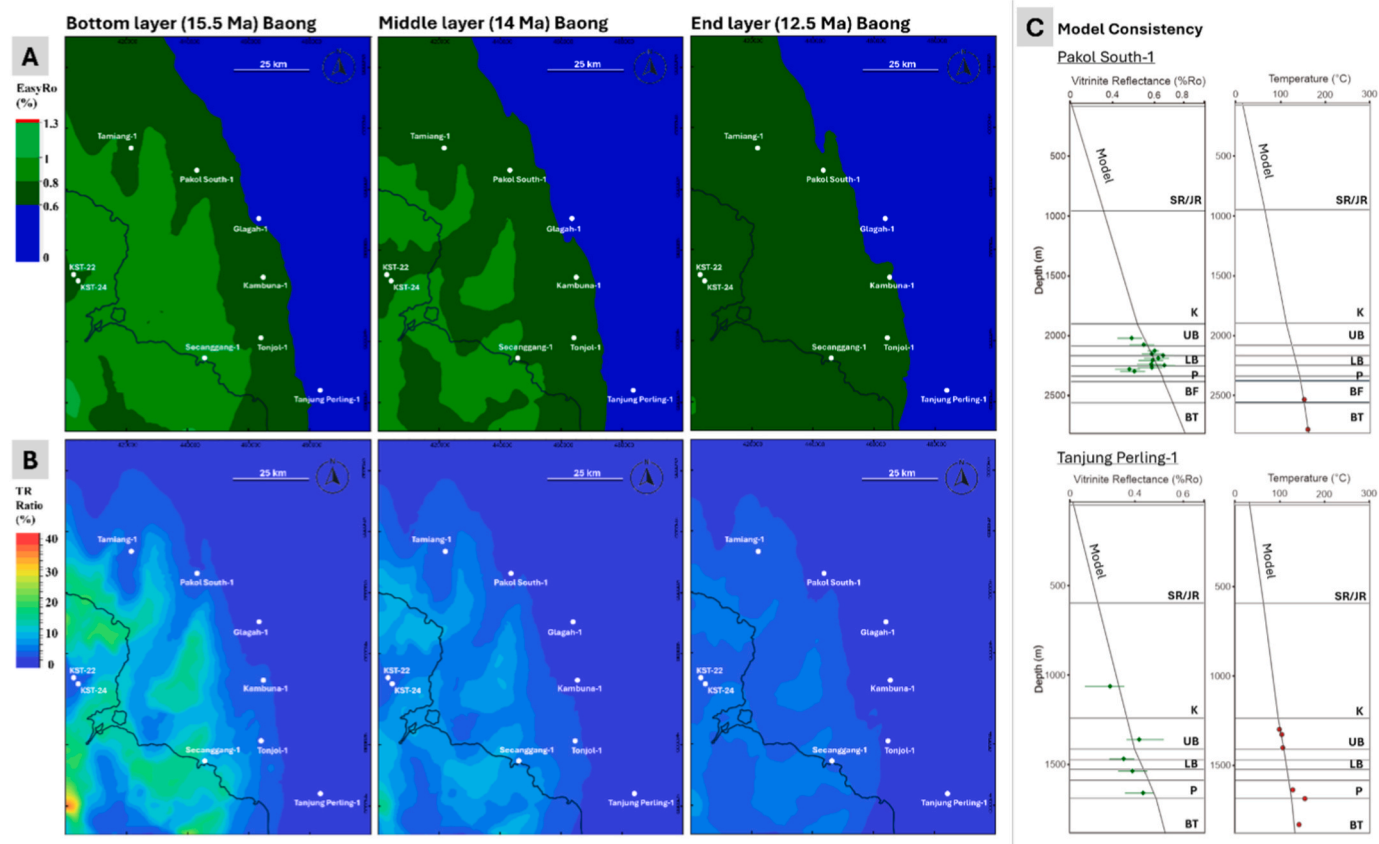


Fig. 10. A) Maturation map of the Baong Shale source rock, divided into three layers: 15.5 Ma, 14 Ma, and 12.5 Ma; B) Transformation Ratio map of the same source rock interval, showing the degree of organic material transformation for each layer; C) Examples of depth plots for vitrinite reflectance and temperature validation from wells Pakol South-1 and Tanjung Perling-1. SR/JR = Seurula-Julu Rayeu Fm; K = Keutapang Fm; UB = Upper Baong Sand; LB = Lower Baong Source Rock; P = Peutu Fm; BF = Belumai Fm; BT = Basement. Note: Remaining well validation can be found in **Supplementary Materials**.

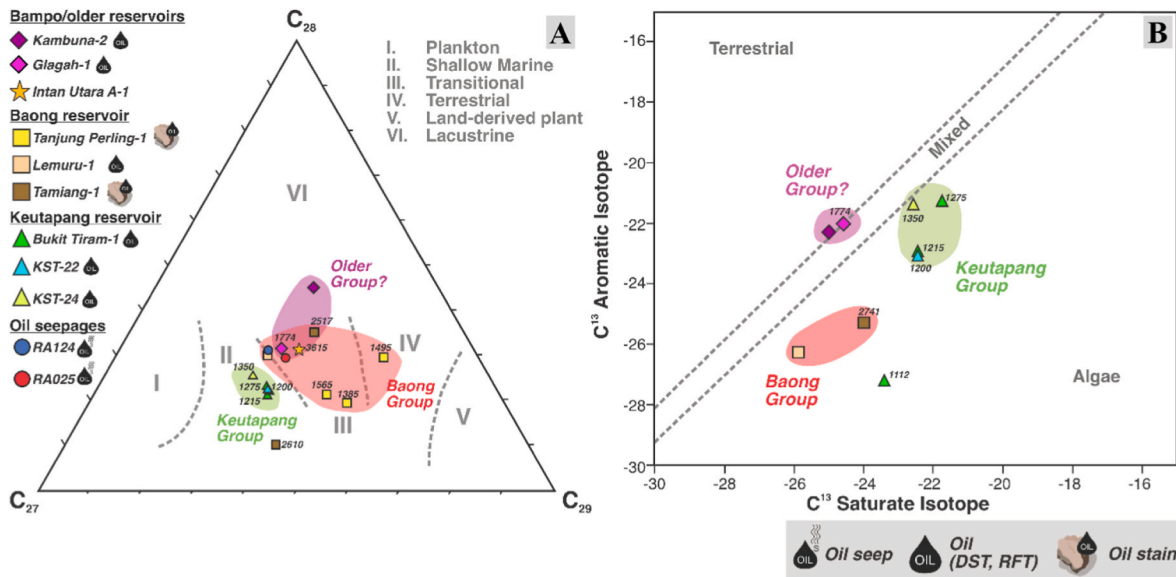


Fig. 11. Trifecta C₂₇-C₂₈-C₂₉ steranes ternary diagram (left; background classification from Huang and Meinschein, 1979) and cross plot of saturate-aromatic carbon isotopes (right; background graph adapted from Sofer, 1984) that shows three oil clusters in different reservoirs.

available for the seepages, their origin may also be algal, as inferred from comparisons of sterane distributions and carbon isotope signatures. The comparison of sterane distributions and carbon isotope signatures reveals conflicting interpretations regarding the origin of Baong Formation oils, leading to uncertainty in identifying their precursors and, unsurprisingly, preventing clear correlation with a specific source (Barber et al., 2005; Lunt, 2019; Aditya et al., 2020).

The PCA results in this study successfully distinguish oils into three groups (Fig. 12A), while the chemometric analysis not only correlates oil families with their respective source rocks but also effectively identifies a mixing phenomenon between oil families (Fig. 12B). The first separation in the chemometric dendrogram appears to be influenced by a combination of mineralogical characteristics and depositional

environment (Fig. 12B). Here, the first right branch in the chemometric dendrogram consists of oils within the Baong Formation reservoir in Tanjung Perling-1 well (Red color, Fig. 12B), a cluster also recognized in the PCA analysis as the Baong Group (Fig. 12A). This Baong Group has distinct characteristics from others, specifically relatively higher TAR (but still low below 1), low drimane/homodrimane, low C₁₅ rearranged bicyclic/bicyclic alkanes, low drimane/C₃₀ hopane, high Tm/Ts, low C₂₇/C₂₉ steranes, and high hopanes/steranes. The nature of low C₁₅ rearranged bicyclic/bicyclic alkanes and high Tm/Ts is known to be related to carbonate-rich source rock as the occurrence of carbonate material can inhibit the transformation of Tm to Ts and re-arrangement of bicyclic alkanes during thermal maturation (Palacas et al., 1984; Price et al., 1987; Hartono et al., 2023). This interpretation is also supported by a

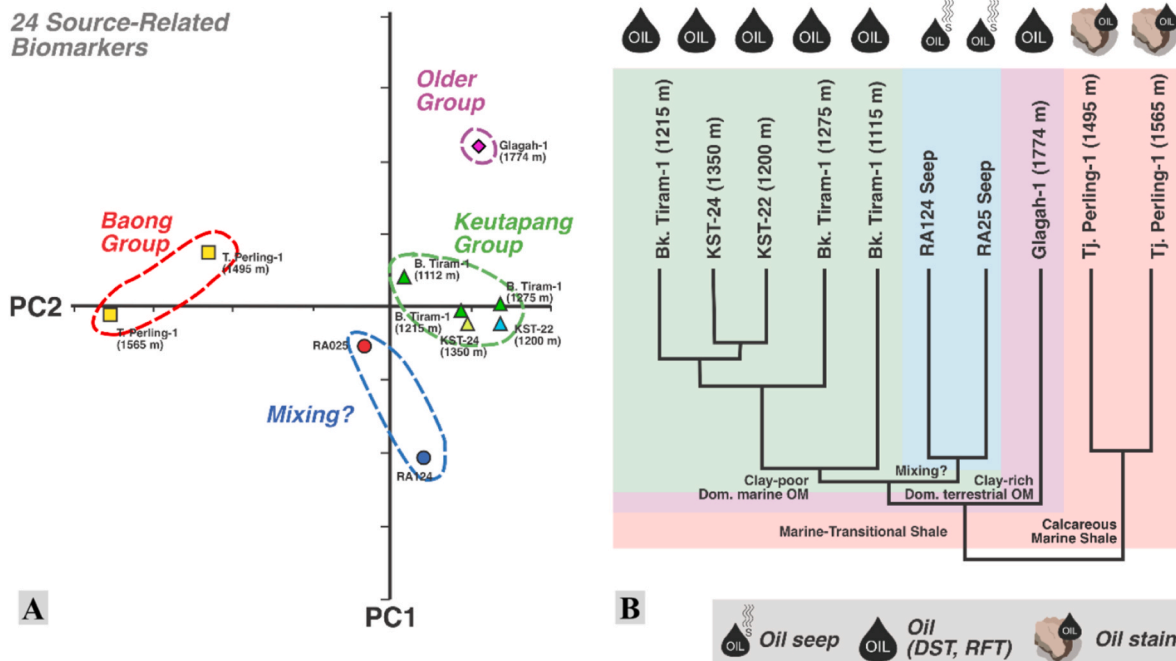


Fig. 12. Principal component (left) and chemometric analysis results (right) based on 24 source-related biomarker parameters that show a clear separation between three oil clusters in different reservoirs and possibly a mixing phenomenon.

prominent peak of 30-norhopane series found in Baong group oil (Fig. 7) that are specific to carbonate lithology (Subroto et al., 1991, 1992). However, the source of the Baong Group in this study is not exclusively derived from carbonate sources, in contrast to the conditions observed in the Seram Basin (Price et al., 1987; Subroto et al., 1991; Hartono et al., 2023), but rather represents a mixture with shale, calcareous shale, or marl, as indicated by the higher C_{30} hopane concentration relative to C_{29} norhopane (Fig. 7). Additionally, the contribution of terrestrial organic matter is evident, as reflected by the presence of land-plant biomarkers such as oleanane and taxodistane (Peters et al., 2005), along with high hopanes/steranes ratios and elevated C_{29} sterane concentrations. It is important to note that the contribution of terrestrial organic matter in this oil group appears to be minimal, as indicated by its low TAR values and the absence of resinous characteristics compared to other oils (Fig. 7). Although this Baong group exhibits relatively high C_{29} sterane concentrations (Fig. 11), these are not necessarily associated with woody material, as they can also originate from marine and lacustrine algae (Volkman, 1986; Kodner et al., 2008; Xu et al., 2019). Thus, the Baong Group oils are most likely derived from calcareous marine shale with a mixed organic matter input, including algae and woody material, deposited under suboxic conditions and correlated with the development of the early Miocene Peutu Formation.

The Baong Formation in the Tanjung Perling-1 well has not yet reached the oil generation window (Fig. 11), thereby ruling out the possibility of lateral migration from coeval Baong shale to the Baong reservoir in Tanjung Perling-1 area. Further analysis of petroleum inclusion data (Fig. 8) reveals the presence of hydrocarbon inclusions within detrital quartz in fracture systems (Fig. 13). This evidence supports the interpretation that petroleum migration likely occurred from an older source rock. The findings are consistent with chemometric analysis, which provides strong evidence that oil migrated from the underlying Peutu Formation into the Baong Formation reservoir. Images of hydrocarbon inclusions within siliciclastic minerals from the Baong Formation in Tanjung Perling-1 are presented in Fig. 13.

The next parallel chemometric branch is interpreted to originate from an argillaceous marine-transitional source rock (purple, Fig. 12B), which further branches into two sub-groups (blue and green, Fig. 12B), likely influenced by variations in clay composition and organic matter

input. The oil hosted in the Malacca reservoir of Glagah-1 is interpreted as a distinct oil family (purple, Fig. 12B), differing from those in the Keutapang interval reservoir due to its relatively high C_{21}/C_{22} tricyclic terpanes, C_{23} tricyclic/ C_{24} tetracyclic terpanes, high C_{28}/C_{29} steranes, low C_{27}/C_{29} steranes, and high diasteranes/steranes. The significantly high diasteranes/steranes ratio in the Glagah-1 oil is likely associated with a clay-rich source rock (Inaba et al., 2001). This association is also supported by high C_{23} tricyclic terpene/ C_{24} tetracyclic terpene indicator. Note that in a more stable environment like carbonate and hypersaline environments, the C_{24} tetracyclic terpene tends to be more dominant (Peters et al., 2005). We interpret this clay-rich lithology as indicative of rapid sedimentation, driven by a high influx of reworked terrestrial organic matter into the basinal area. This is supported by high C_{28}/C_{29} steranes ratios together with low C_{27}/C_{29} steranes ratios (woody OM indicator). On the other hand, the Oligocene rifting event was marked by rapid paleo-bathymetric changes (Lunt, 2019), which likely enhanced erosion and facilitated the deposition of continental argillaceous materials mixed with organic matter. Therefore, the Glagah-1 oil most likely correlates with the syn-rift Oligocene Bampo Formation, as it is derived from a marine-transitional environment characterized by rapid sedimentation and terrestrial organic matter input.

The oil family accumulated in the younger reservoir of the Keutapang Formation is interpreted to have originated from a marine-transitional source rock with lower argillaceous input and a higher contribution from plankton (green color, Fig. 12A). A high C_{27}/C_{29} steranes ratio suggests a dominant contribution from marine plankton precursors (Fig. 11) with minor terrestrial organic matter input, as evidenced by the prominent peaks of oleanane, bicadinanes, and taraxastane (Fig. 7). This Keutapang group oils exhibit moderate diasteranes/steranes and C_{23} tricyclic/ C_{24} tetracyclic terpanes ratio, suggesting a moderate contribution of argillaceous material (Inaba et al., 2001; Peters et al., 2005). Note that the diasteranes/steranes and C_{23} tricyclic/ C_{24} tetracyclic terpanes ratio further differentiate the Keutapang Group from the higher ratios observed in the Glagah-1 oil. On the other hand, the carbonate-associated biomarkers found in the Baong Group oil also do not exist in the Keutapang oil family. Therefore, we suggest that a more stable marine environment, likely positioned farther from carbonate-associated organic matter influence, is required for the source rock of this oil family. In this setting, the deposition of the Lower Baong Shale of the Baong Formation represents the most suitable candidate for the source rock, as it developed in bathyal conditions (Lunt, 2019) with intermittent slumping of terrestrial deposits from the west (Adlan et al., 2025). Pyrolysis data from the Baong Formation from unpublished government reports further support the co-occurrence of Type II and Type III kerogen (Fig. 14). Overall, this study provides novel evidence confirming the Baong Formation, particularly the lower Baong Shale, as the primary source rock for the oils accumulated in the Keutapang reservoir.

The Baong Formation in Pakol South-1 has reached the oil maturation window (Fig. 11). At the same time, the petroleum inclusion stratigraphy from the same interval (Fig. 8) shows that the entire Baong Formation in this well contains hydrocarbon inclusions. The presence of hydrocarbon inclusions in both siliciclastic and carbonate stringers within the lower section of the Baong Shale source rock suggests that these interbedded lithologies may have acted as transient reservoirs or conduits for hydrocarbon migration during expulsion (Fig. 8), potentially enabling both lateral-coeval migration (self-sourcing) and conventional migration into the overlying Keutapang Formation. Images of hydrocarbon inclusions in Pakol South-1 are presented in Fig. 13.

The chemometric and PCA analyses in this study are also capable of identifying oil family mixing, particularly in the seep samples (Blue color, Fig. 12B). The biomarker characteristics of the two oil seeps closely resemble those of Keutapang oils expelled from the middle Miocene, lower Baong source rock, both qualitatively (Fig. 7) and quantitatively. The similarity lies in the relatively similar ratios of n-alkanes/isoprenoids, tricyclic terpanes, Tm/Ts, and C_{27}/C_{29} steranes

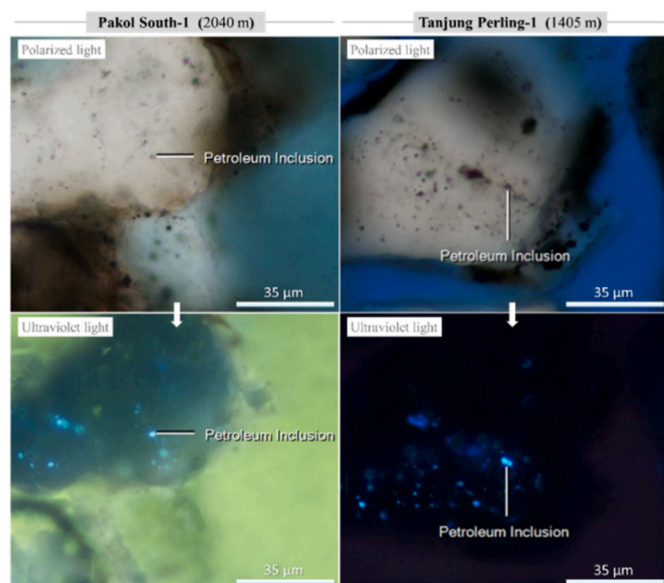


Fig. 13. Microscopic polarization (top) and fluorescence microscopy (bottom) images showing petroleum inclusions within fractures in detrital quartz: Left – Baong Formation, Pakol South-1 at 2040 m, exhibiting blue fluorescence; Right – Tanjung Perling-1 well at 1405 m, displaying petroleum inclusions with brighter blue fluorescence.

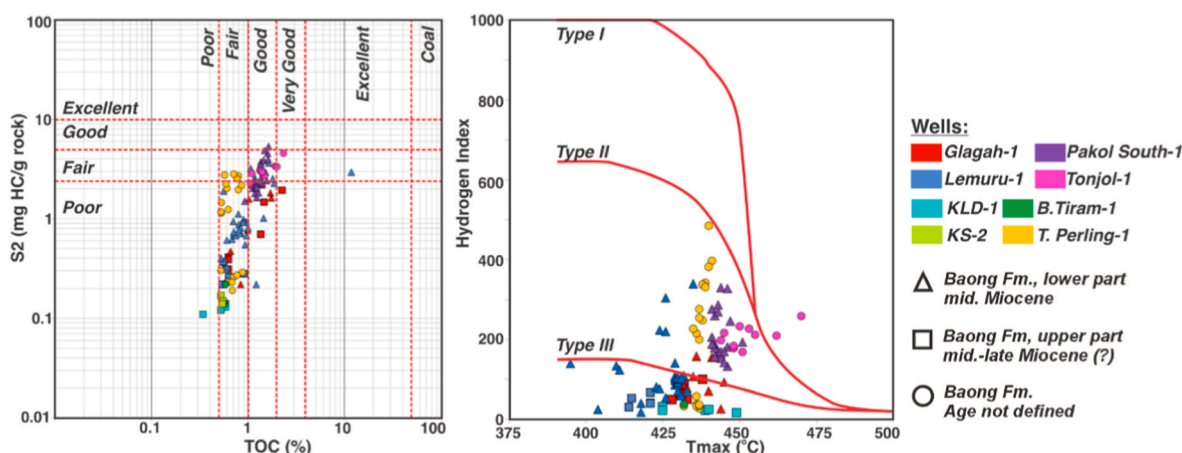


Fig. 14. Pyrolysis data and TOC from the Baong Formation from an unpublished report by the Ministry of Energy and Mineral Resources of Indonesia, further support the co-occurrence of Type II/III kerogen in the formation.

compared to the Keutapang oils. The oil seep samples display fingerprints closely matching those of the Keutapang reservoir oils, including distinct bicadinane peaks and similar tricyclic terpane patterns (Fig. 7), corroborating that they are derived from a similar source. However, the main discrepancy lies in the high hopanes/steranes ratio, likely resulting from a different oil family, implying migration from the early Miocene Peutu Formation source rock (Baong group-oil family). Thus, we suggest that the mixing mechanism of the oil families occurred as a result of the combined lateral migration from the lower Baong source rock and fault-mediated migration from the older Peutu source rock.

5.2. Middle Miocene Baong Shale in the eastern NSB

The Lower Baong Shale has been reported to contain TOC values ranging from 0.54 % to 1.62 %, with most measurements exceeding 0.9 % (Courteney, 1988; Anderson et al., 1993; Caghey and Wahyudi, 1993; Kirby et al., 1993). Data from Pakol South-1 and Tanjung Perling-1 confirms that the TOC values remain within a similar range of 0.5 %–1.17 %, characterized by a mixed kerogen composition of Type II and Type III. SEM and EDX analyses from unpublished reports from Tanjung Perling-1 reveal siderite in two forms: as a microcrystalline replacement of the detrital clay matrix (Fig. 15), and as grain coatings and nodules. These features are especially prominent in the blocky sandstone interval between 1324 and 1349 m (Fig. 8). Rare occurrences of framboidal pyrite filling intergranular pores are observed within foraminiferal chambers (e.g., Fig. 13). The presence of authigenic

framboidal pyrite and microcrystalline siderite coating grains indicates early diagenetic processes that occurred under low-oxygen or reducing conditions (Wignall et al., 2005; Bojanowski and Clarkson, 2012). The pyrite occurrence within foraminiferal chambers specifically suggests a depositional setting with intermittent oxygen availability (dysaerobic to anoxic), such as in continental shelf sediments or within certain marine basins where oxygen is limited due to slow sedimentation or organic matter presence (Raiswell and Berner, 1985; Wignall et al., 2005).

Grain-coating clays composed of authigenic chlorite, along with mixed-layer illite/smectite (Fig. 15), are also observed between 1366 and 1516m (Fig. 8). Chlorite grain coatings support early diagenetic conditions involving iron-rich, slightly reducing pore waters (Humphreys et al., 1994). The presence of mixed-layer illite/smectite (I/S) as grain coatings and within the matrix suggests mineral transformations linked to intermediate to deep burial and hydrocarbon generation under elevated thermal regimes (Foscolos and Powell, 1979; Pollastro, 1990). The presence of both chlorite and mixed-layer illite/smectite may reflect hydrothermal activity (Ruggieri et al., 2006; Fulignati, 2020); more importantly, these mineralogical transformations offer valuable insights into fluid-rock interactions, particularly involving carbonate minerals (Adlan and John, 2023; Ehrenberg et al., 2024). One implication is that this interval likely experienced fluid influx, either from hydrothermal brines or fluids expelled from deeper formations during hydrocarbon expulsion. These processes likely contributed to the formation of thin dolomite stringers interbedded with limestone layers in the mid to upper Baong interval, as documented in

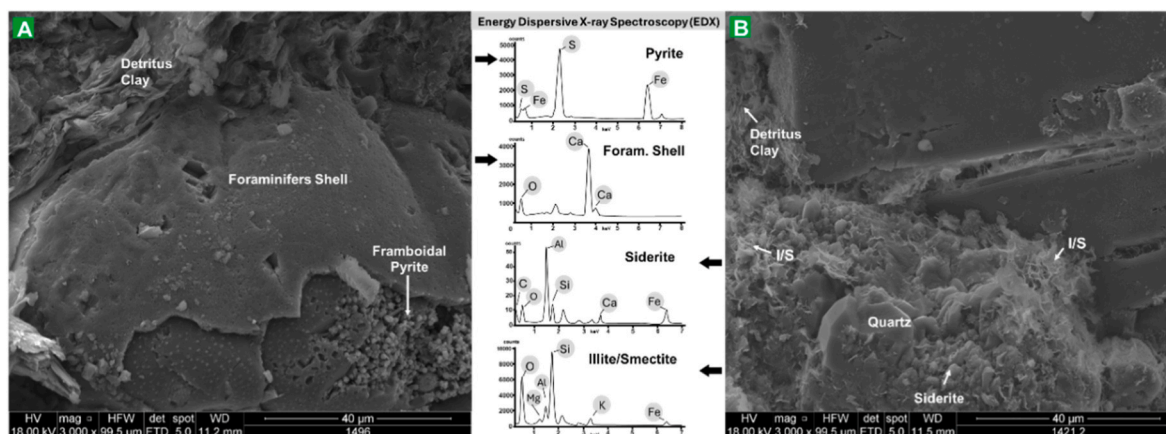


Fig. 15. SEM imaging and Energy Dispersive X-ray Spectroscopy of the Lower Baong Shale from the unpublished Tanjung Perling-1 well report. A) Framboidal pyrite replacing foraminiferal shells. B) Identification of Illite-Smectite and siderite in the interval.

the Tanjung Perling-1 well report. Therefore, it is suggested that the dolomite formed through late-stage recrystallization (Adlan et al., 2023; Ehrenberg et al., 2024), rather than early deposition, possibly reflecting vertical fluid migration through fractures that predominantly impacted the upper-sand units of the Baong interval (Fig. 8).

5.3. Mass-transport processes and the formation of stratigraphic traps

The first recognized turbidite reservoir in Indonesia, known as the Middle Miocene Besitang River Sand, is located in the NSB (Mulhadiyono and Soedaldjo, 1978) (Fig. 16). The origin of Middle Miocene turbidite sandstones in the NSB remains debated (Syarifuddin and Ariyanto, 2018), with two primary sediment sources proposed: the uplifted Barisan Mountains to the south or southwest, and the Malacca Platform to the northeast. Several studies favor a northeastern origin from the Malacca Platform. Ambarwati et al. (2017) strongly argue for a Malacca-derived deep marine fan system, supported by Nur'aini et al. (2000), Lunt (2019), and Wardhana et al. (2022), who interpret sediment supply from paleo-highs or shelfal regions in the east. Interestingly, some interpretations continue to support a Malacca provenance, even in cases where seismic evidence indicates sediment transport directions from the south or southeast, an orientation that would more plausibly suggest a Barisan source (Arisandy et al., 2024).

On the other hand, some evidence suggests a southwestern source from the Barisan Mountains. Syafrin (1995) reported incised valley systems interpreted as fluvial pathways originating from the Barisan margin. Hakim et al. (2019) described turbidite fans likely sourced from the south, and Basundara and Mardianza (2017) identified a coastal belt sand system associated with sediment input from the Barisan hinterland. The coexistence of these contrasting interpretations suggests that both sediment sources may have been active, either sequentially or concurrently, in different parts of the basin. However, a recent study indicates that the Middle Miocene turbidite sandstones forming the stratigraphic trap are confined to the southwest portion of the study area (Adlan et al., 2025) (Zone-A, Fig. 17B).

Each provenance represents a different mass-transport depositional model. Sediment derived from the Malacca Platform would likely

produce stacked submarine lobes typical of shelf-fed lowstand systems, where repeated collapse of delta-front sediments forms vertically stacked sand bodies (e.g., Steventon et al., 2020). However, such geometry is not observed in the Lower Baong (Mulhadiyono and Soedaldjo, 1978). Instead, the sandstone lenses appear isolated and discontinuous, lacking vertical stacking, suggesting emplacement by discrete mass-transport events rather than sustained deltaic progradation (Basundara and Mardianza, 2017; Wardhana et al., 2024). This observation supports Barisan Mountains origin (Fig. 16). In the Middle Miocene, two key geological scenarios may explain sediment delivery from the south. One is the initial uplift of the Barisan margin (Cameron et al., 1980; Davies, 1984), and the other is the development of regional dextral strike-slip faulting (Barber et al., 2005; Adlan et al., 2025). This uplift likely caused slope oversteepening, and when slope failure occurred, substantial volumes of coarse clastics were transported downslope (Mulhadiyono and Soedaldjo, 1978; Bahesti et al., 2013; Adlan et al., 2025) delineated the area where the turbidites likely developed, further supporting their derivation from the Barisan orogenic front and reinforcing the interpretation of a southern sediment source during the Middle Miocene. Additionally, the absence of extensive stacked lobe architecture weakens the interpretation of a Malacca Platform source.

The emplacement of these turbidites reflects the interaction of pre-conditioning factors (i.e., factors that prime the sediment to fail) and trigger mechanisms, which initiate the failure (e.g., Scarselli, 2020). Key preconditioning factors include rapid sediment accumulation, slope oversteepening from flexural subsidence, and the presence of over-pressured shales (e.g., Stigall and Dugan, 2010). Likely triggering mechanisms include seismicity related to ongoing thrusting, pore pressure buildup, and potentially sea-level fluctuations (Nelson et al., 2011; Nugraha et al., 2020; Steventon et al., 2020). Importantly, slope failure in the study area does not appear confined to lowstand conditions (Adlan et al., 2025), as predicted by conventional sequence stratigraphic models (e.g., Weimer, 1990; Kolla and Perlmutter, 1993). As observed in both compressional settings (e.g., Dalla Valle et al., 2013) and passive margins (e.g., Steventon et al., 2020), slope collapses and turbidite emplacement can also occur during sea-level rise or highstand, when

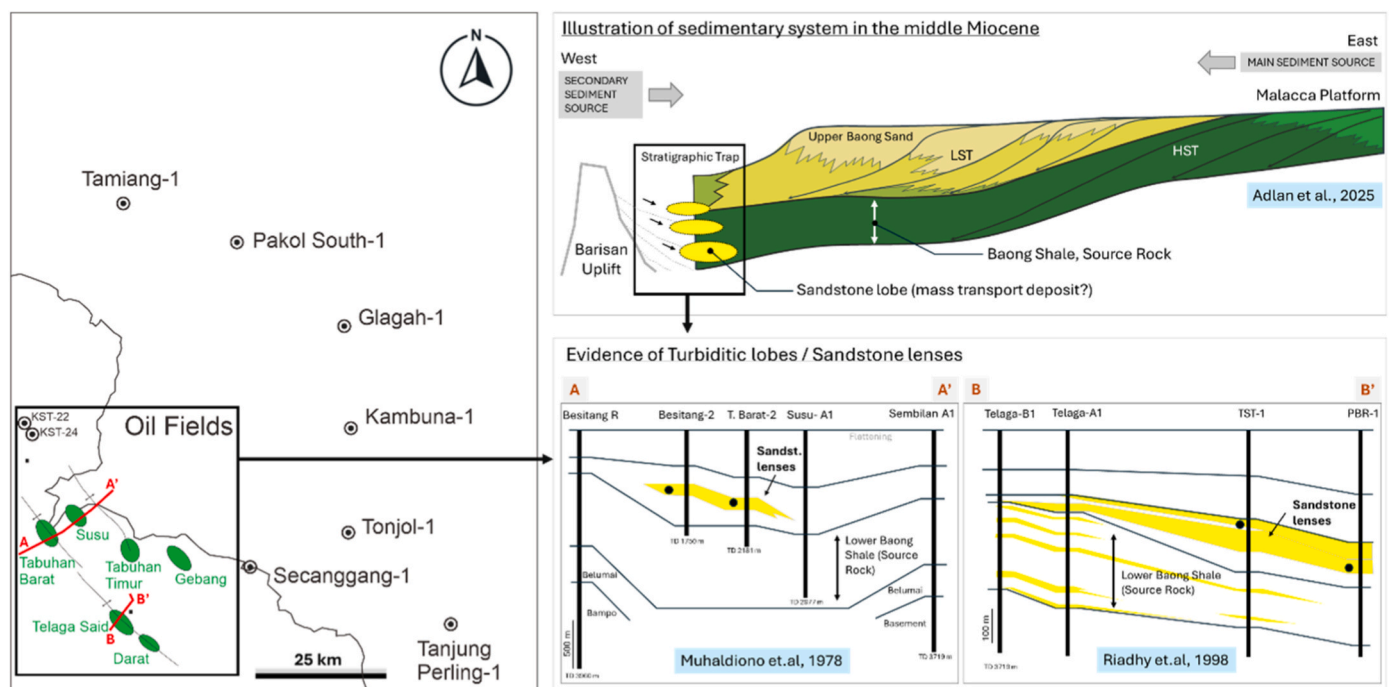


Fig. 16. Distribution of onshore oil fields producing from Middle Miocene Baong reservoirs (left), alongside a conceptual model illustrating the stratigraphic play in the study area (right).

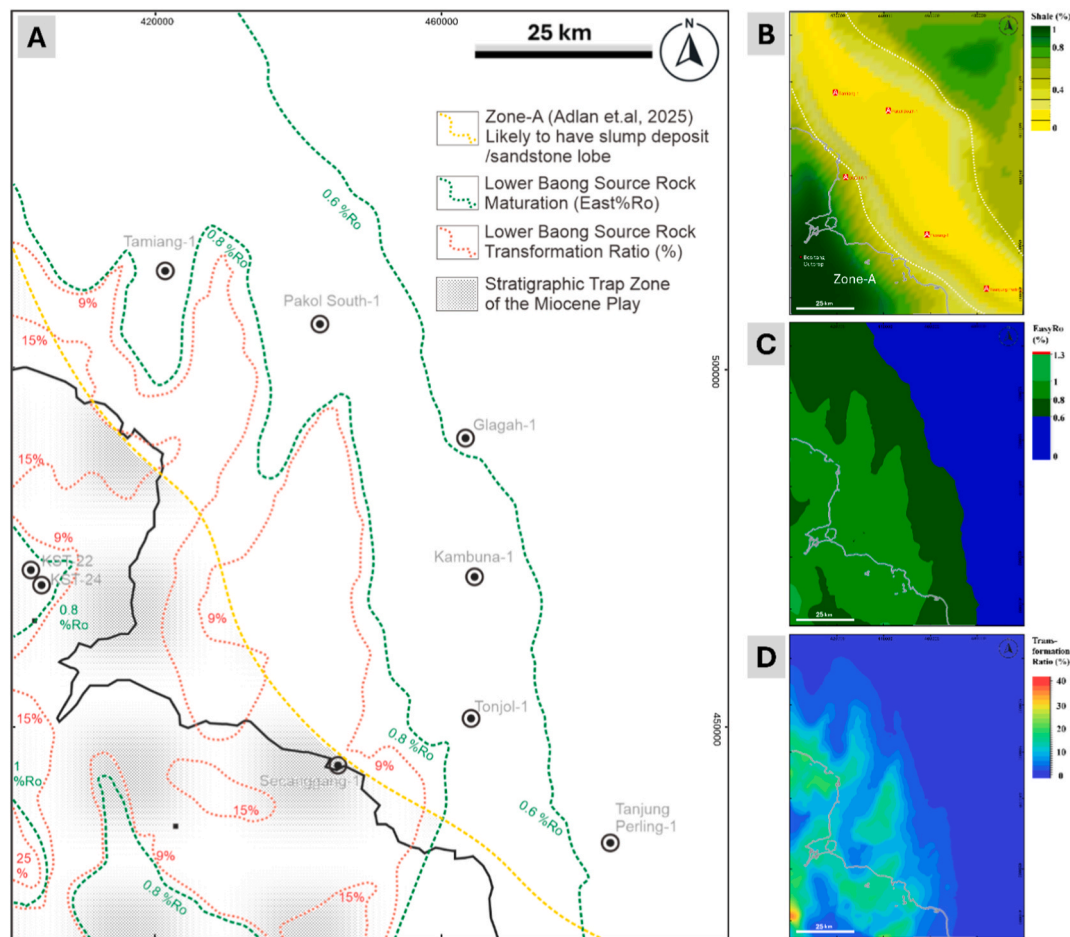


Fig. 17. (A) Compounded zonation for delineating self-sourcing stratigraphic zone-plays using a combination of BPSM and SFM, derived from: (B) detailed stratigraphic study results (Adlan et al., 2025) identifying Zone A in the southwest as a potential stratigraphic trap area, (C) shale maturity map from this study, and (D) shale transformation ratio map highlighting areas most likely to have expelled hydrocarbons into adjacent traps.

preconditioned slopes become overloaded by continued sediment input.

In the Lower Baong Shale, the discrete sand bodies are fully encased within a thick, overpressured marine mudstone that acts as both top and lateral seal. Stratigraphic traps form where turbidite lobes pinch out or onlap onto basin-floor topography (e.g., Algar et al., 2011; Kneller et al., 2016). This trapping style is not structurally controlled but relies entirely on facies relationships. Therefore, the deposition of the Lower Baong turbidites within a transgressive shale interval suggests the operation of a non-classical timing mechanism, emphasizing the role of tectonics and sediment flux over relative sea-level position alone. This study suggests the timing of turbidite development to coincide with Early Miocene dextral strike-slip tectonics, preceding the peak of the Barisan uplift, as outlined by Adlan et al. (2025).

5.4. De-risking exploration zones for stratigraphic plays

De-risking exploration zones for stratigraphic plays requires a systematic approach that evaluates four key elements: source rock, reservoir, trap (or seal), and dynamics, including timing and migration (Otis and Schneidermann, 1997; Lockhart et al., 2018; Bond et al., 2022). This study applies the framework to address key elements specific to self-sourcing stratigraphic plays (Fig. 17): First, the presence of a mature source rock is evaluated through basin and petroleum system modeling, which examines the maturation and transformation ratios of the source rock. Stratigraphic forward modeling is then used to analyze the thickness, consistency, and TOC distribution. Second, to assess the presence of a reservoir rock, stratigraphic traps, such as turbidite sands, are

identified and zoned through stratigraphic forward modeling (e.g., Adlan et al., 2025). At this stage, the presence of a trap is naturally addressed, as the first two steps delineate stratigraphic traps where sandstones are enclosed by shale. Finally, play dynamics are examined using geochemical proxies, such as oil-to-source correlation, chemometric analysis, and hydrocarbon fluid inclusion analysis. By applying this methodology, we offer a cost-effective approach for evaluating exploration zones with limited well and seismic data, conditions typical in frontier areas. This framework allows for the identification of high-potential exploration areas while reducing the risks associated with expensive data acquisition, such as 3D seismic surveys. Note that the effectiveness of this de-risking approach depends on the coverage and quality of existing data to validate forward model results in exploration areas.

5.5. Implications for the regional petroleum system

The Oligocene Bampo Formation and Early Miocene Belumai-Peutu Formation are widely recognized as the primary and secondary hydrocarbon source rocks in the NSB (Buck and McCulloh, 1994). Although the younger lower-Baong Shale has been proposed as a potential source rock in several studies (Kjellren and Sugiharto, 1989; Kirby et al., 1993), conclusive geochemical evidence linking it directly to produced hydrocarbons remains limited, with some studies suggesting that the Baong Shale may be too immature to serve as a viable source rock (Anderson et al., 1993). This study provides conclusive evidence that refines the understanding of the petroleum system in the NSB,

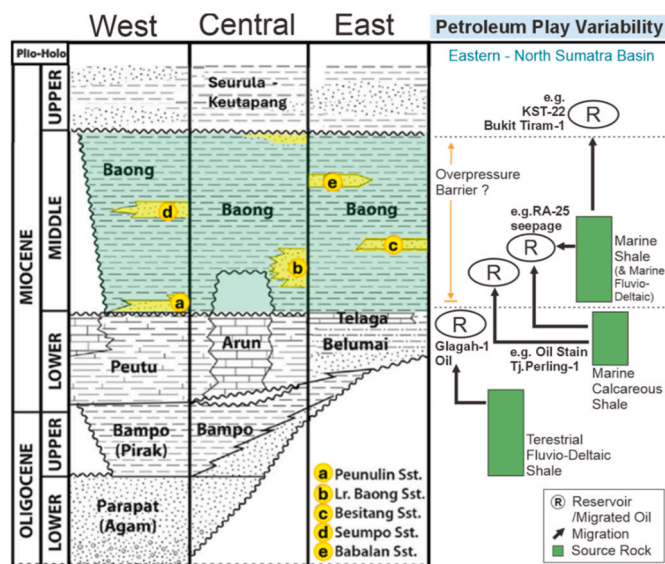


Fig. 18. Three main source rock intervals and four distinct types of hydrocarbon accumulations in the NSB, illustrating the presence of stacked, regionally variable petroleum systems with both structural and stratigraphic trapping styles.

emphasizing the interplay between multiple source rocks and diverse reservoir targets. The findings support the existence of three main source rock intervals and four distinct types of hydrocarbon accumulations (Fig. 18), one of which is the self-sourcing stratigraphic trap. The four hydrocarbon accumulation types include: The Oligocene syn-rift source charges Lower Miocene carbonate reservoirs, representing the earliest viable petroleum system phase. The Early Miocene calcareous source charges Middle Miocene turbidite reservoirs. The combined Early and Middle Miocene source rocks charge the Baong Interval reservoirs, indicating overlapping expulsion windows and the presence of structural or stratigraphic traps. Lastly, the Middle Miocene Baong Shale sources younger Keutapang Formation reservoirs, suggesting vertical migration through fault-assisted pathways and ongoing charge in younger stratigraphy. The implications for exploration are significant: rather than a single play model, the NSB hosts stacked and regionally variable systems with both structural and stratigraphic trapping styles.

6. Conclusion

This study outlines a systematic approach for exploring areas with potential stratigraphic traps and lateral petroleum migration between coeval source rocks and reservoirs (self-sourcing). The process consists of four key stages: (1) assessing geochemical evidence to identify potential plays, (2) using stratigraphic forward modeling to delineate zones of potential sand lenses, (3) Using stratigraphic forward modeling to simulate organic matter distribution in the source rock that envelops the sand lenses, and (4) applying basin and petroleum system modeling to evaluate the source rock maturation and expulsion potential. This approach provides a framework for early-stage exploration, helping identify self-sourcing stratigraphic plays and de-risk prospective zones before investing in costly data acquisition like 3D seismic surveys.

This study highlights the complexity of the NSB petroleum system, where three source rocks with similar organic matter generate oils with indistinguishable marine signatures. Biomarker-chemometric analysis differentiates three oil families: Baong-reservoir oil (marine calcareous shale, Peutu/Belumai-equivalent source), Glagah-older oil (terrestrial fluvio-deltaic shale, Bampo Formation source), and Keutapang-reservoir oil (marine shale, lower Baong-shale source). These results provide the first geochemical evidence of oil mixing in the region and deliver conclusive petroleum system insights with the potential to

fundamentally redefine exploration strategies.

CRediT authorship contribution statement

Qi Adlan: Writing – review & editing, Writing – original draft, Visualization, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Barry M. Hartono:** Writing – review & editing, Methodology, Investigation, Formal analysis. **Harya D. Nugraha:** Writing – review & editing, Investigation, Formal analysis. **Adhipa Herlambang:** Writing – review & editing, Investigation, Formal analysis. **Waleed AlGharbi:** Writing – review & editing, Validation, Software, Methodology, Investigation. **Eriko Sabra:** Writing – review & editing, Resources, Project administration.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at <https://doi.org/10.1016/j.marpetgeo.2025.107611>.

Data availability

The authors do not have permission to share data.

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